WELL CONSTRUCTION, OPERATING AND PLUGGING DETAILS

CTV I ELK HILLS 26R PROJECT

Injection Well 345C-36R

Facility Information

Facility Name: Elk Hills 26R Storage Project

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Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_345C-36R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – COP Details_345C-36R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – COP Details_345C-36R_V3	3	1/10/23	Revisions made based on questions received from the EPA 01/06/23

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

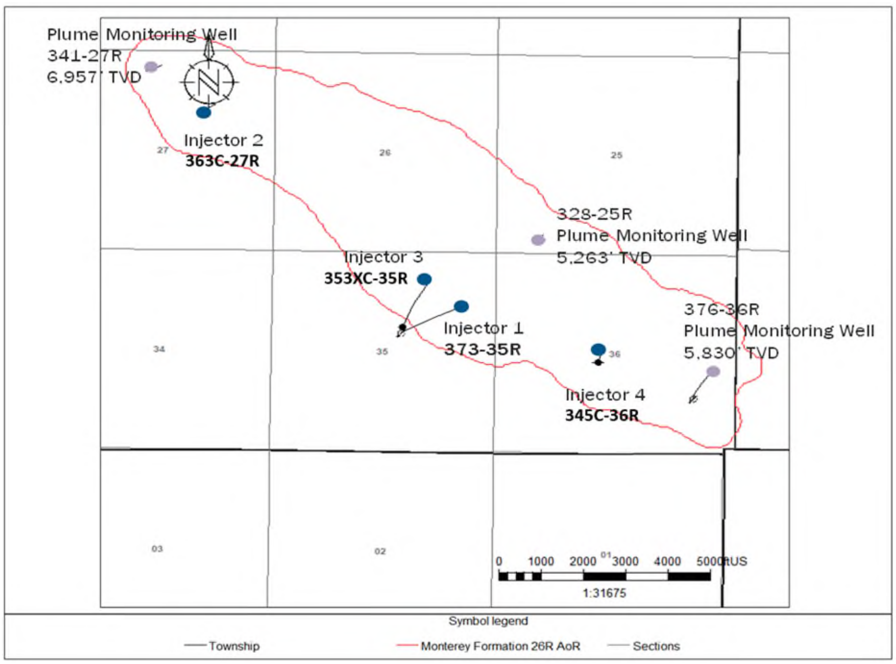

Figure 1: Map showing the location of injection wells and monitoring wells.

The *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Construction

Construction of new injection and monitoring wells will occur during pre-operational testing. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates: to prevent migration of fluids out of the injection zone, to protect the shallow formations, and to allow for monitoring, as described by the following.

- Well designs will be sufficient to withstand all anticipated load cases including safety factors
- Multiple cemented casing strings will protect shallow formations from contacting injection fluid
- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and MIT to be conducted
- All wellhead equipment and downhole tubulars will be designed to accommodate the dimensions necessary for deployment of monitoring equipment such as wireline-conveyed logging tools and sampling devices
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion.

- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
- Casing – 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement – portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 where good cement bond between formation and casing exists.
- Tubing – 13Cr L-80 or other corrosion resistant alloy
- Packer – corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing and Cementing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section.

The 26R reservoir has been depleted and reservoir pressure is low. The temperature is approximately 210 degrees Fahrenheit. These conditions are not extreme, and CTV has extensive experience successfully constructing wells in depleted reservoirs. Standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Operational parameters acquired throughout the cementing operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

Table 1: Casing Specifications

Name	**Depth Interval (feet)**	**Outside Diameter (inches)**	**Inside Diameter (inches)**	**Weight (lb/ft)**	**Grade (API)**	**Design Coupling (Short or Long Threaded)**	**Thermal Conductivity @ 77°F (BTU/ft hr, °F)**	**Burst Strength (psi)**	**Collapse Strength (psi)**
Conductor	14' - 54'	20	19.124	94	H-40	Short	2.62	1530	520
Surface	14' - 2400'	9.625	8.835	40	L-80	Long	2.62	5750	3090
Long string	14' - 5600' 5600' - 6000'	7	6.276	26	L-80 L-80 CRA	Long	2.62	7240	5410
Liner	5700' - 7980'	4.5	3.92	13.5	L-80 CRA	Long	2.62	9020	8540

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

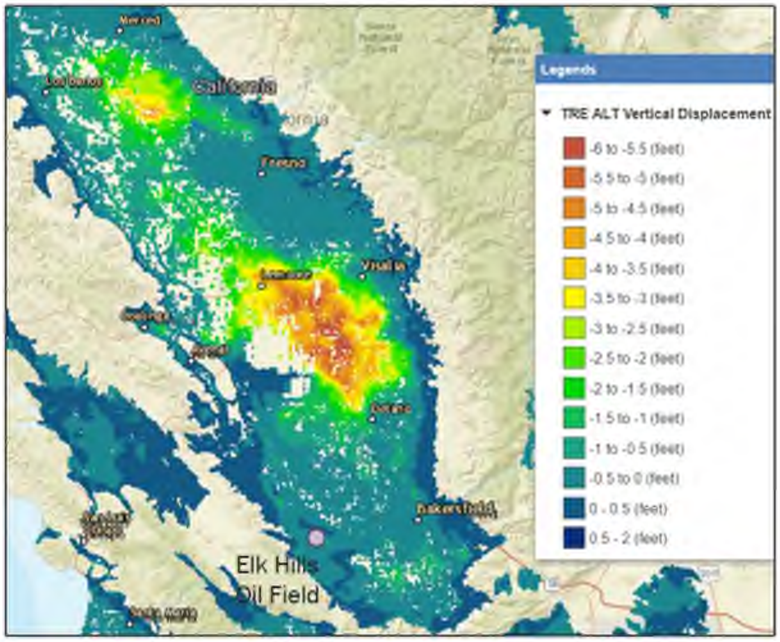

Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Tubing and Packer

The information in the tables provided in the Tables 2 and 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined prior to completion during pre-operational testing. A suitable corrosion-resistant alloy will be selected and installed once the CO_2 stream impurities and impurity concentrations have been determined. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel.

Table 2: Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	5,700	4.5	4.00	11.6	L-80 CRA	Premium	7,780	6,350

Table 3: Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	5,700	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rates, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan detail the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design 345C-36R with a surface shut-off valve at the wellhead and not a down-hole device.

<u>Pre-Injection Testing Plan</u>

The following tests and logs will be acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring document.

Deviation Checks

Deviation measurements will be conducted approximately every 120’ during construction of the well.

Tests and Logs

The following logs are expected to be acquired during the drilling or prior to the completion of 345C-36R:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Mud Log
- Acoustic Cement Bond Log

Demonstration of mechanical integrity

Table 4: Summary of tests to be performed prior to injection

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Annulus Pressure Test Procedures

1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.
2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test.

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less equal to or greater than the highest annular pressure specified in the Operating Procedures document. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve.
4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals. The annulus system must remain isolated for a period of no less than 60 minutes.

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Injectivity and Pressure Fall-Off Testing for Injection Wells

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV will complete injectivity and pressure fall off testing prior to CO_2 injection, pursuant to 40 CFR §146.87(e).

CTV will consider pressure fall-off testing throughout the injection phase to complement reservoir monitoring if injection rate decreases along with a simultaneous injection pressure increase outside the results from computational modeling.

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

A surface gauge at the wellhead and a downhole gauge set above the packer with real-time surface readout capability will be used for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

<u>Well Operations</u>

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of CO_2 over the life of the project.

For a target rate of 18.75 MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been calculated assuming 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection - as the 26R reservoir is depleted in pressure - a surface pressure and down hole injection pressure (calculated at top perforation) of 1015 psi and 1993 psi respectively is expected to be required to achieve the target rate. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface pressure and down hole pressures (calculated at top perforation) required are 1515 psi and 3555 psi respectively.

Based on fracture stimulation data from well 388-26R in the 26R reservoir, the expected fracture gradient is 0.701 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum downhole injection pressure is 3,847 psi (calculated at the top perforation). The injection well will be controlled using automation to never exceed this bottomhole pressure. 40+ years of gas and water injection experience into the Monterey Formation 26R reservoir supports that this is an appropriate and effective operating limit.

The expected pressures over the life of the project are summarized in Table 5.

Table 5: Proposed operational procedures

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.701psi/ft fracture gradient with 10% safety factor	
Surface	1888	psig
Downhole	3847	psig
Injection Pressure @ Target rate	Expected range over project life	
Surface Start / End	1,015 / 1,515 / 1265*	psig
Downhole Start / End	1,993 / 3,555 / 2774*	psig
Target Injection Rate	18.75* 993	mmscfpd Tonnes/day
Maximum Injection Rate	25** 1,324	Mmscfpd Tonnes/day
Annulus Pressure	Expected range over project life	
Surface Start / End	100 / 995 / 548	psig
Downhole Start / End	2626 / 3521 / 3074	psig
Annulus / Injection Tubing Pressure Differential	>100	psig

**Downhole and Surface pressures estimated at Target rate from Plume model and Prosper modeling respectively*
***Well only expected to be operated at maximum injection rates for short periods of time for Project flexibility*

Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 5 are suitable to the well design and will not impact the well integrity or induce formation fracture.

Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

The expected average Injection rate for the well is 18.75 million standard cubic feet, and the maximum total storage for the project is 38 MMT of CO_2. The injector is expected to go over this average injection rate for short periods of time for Project flexibility, however, the total storage of the project is not expected to exceed the previously stated maximum.

At this time, for injection well 345C-26R, CTV expects a maximum injection rate of 25 million standard cubic feet and a maximum injection pressure of 3847psi (90% of the fracture pressure calculated at the top perforation using a 0.71psi/ft fracture gradient). To account for fluctuations in the daily operating rates and pressure, a threshold of 10% below the maximum rate and 8% below the maximum injection pressure will be used to configure the automation and alarms, which equates to a rate threshold of 22.5 million standard cubic feet and 3555psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

Shutdown Procedures

Under routine conditions (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 165 tons per day over a 6-day period to ensure protection of health, safety, and the environment. This same procedure applies to routine shutdowns and to the gradual shutdowns described in the Attachment F – Emergency and Remedial Response plan.

Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and/or digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

Injection Well Plugging

CTV will conduct injection well plugging and abandonment according to the procedures below. The proposed injection well plugging plan will ensure that the proposed materials and procedures for injection well plugging are appropriate to the well's construction and the site's geology and geochemistry.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures.

Table 6: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	3.92	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	7900	2563	1135	39
Sacks of cement to be used (each plug)	168	24	24	5
Slurry volume to be pumped (bbl)	34.41	4.92	4.92	1.02
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	5600	2438	1010	14
Bottom of plug (ft)	7900	2563	1135	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or CT Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.
2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. Wellbore Bullheading will be conducted at appropriate rates so as to ensure no fracturing of the surrounding formation occurs and the cement plugs are not compromised in any way. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.
3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).
4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.
5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.
6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.
7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.
8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

9. Once the fourth cement plug is placed at surface, casing will be cut 5’ below ground level. A metal cap will be welded onto the top of the cut casing, stamped with the well name and API. Surface location will then be backfilled and restored to pre-operation conditions.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):
  - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.
  - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.